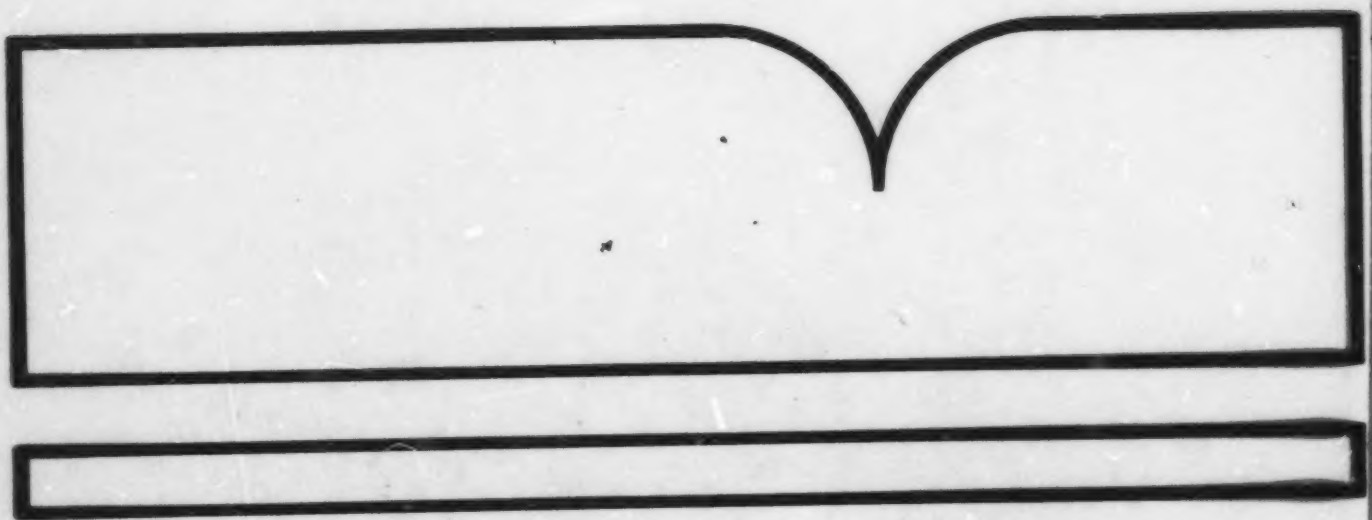
PB81-119422

Flue Gas Desulfurization Pilot Study
Summary of Phase I and Phase II Reports

NATO Committee on the Challenges of Modern
Society, Brussels (Belgium)

Apr 80



U.S. Department of Commerce
National Technical Information Service
NTIS

PB81-119427

COMMITTEE ON
THE CHALLENGES OF
MODERN SOCIETY

FLUE GAS DESULFURIZATION PILOT STUDY SUMMARY OF PHASE I AND PHASE II REPORTS

April 1980

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA 22161

NORTH ATLANTIC TREATY ORGANIZATION

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-600/8-80-043		PB81 119422

4. TITLE AND SUBTITLE	5. REPORT DATE
Flue Gas Desulfurization Pilot Study Summary of Phase I and Phase II Reports	August 1980 Issuing Date.
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
North Atlantic Treaty Organization (NATO) Committee on the Challanges Modern Society (CCMS)	
9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
North Atlantic Treaty Organization	INE 828
	11. CONTRACT/GRANT NO.
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
Office of Research and Development U.S. EPA Washington, D.C. 20460	14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT

The initial phase of this study consisted of a survey of existing FGD systems used on larger combustion processes in the NATO countries and Japan.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
	Flue Gas Desulfurization NATO	

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES
Release Unlimited	unclassified	
	20. SECURITY CLASS *(This page)*	22. PRICE
	unclassified	

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

Flue Gas Desulfurization Pilot Study

Summary of Phase I and Phase II Reports

April 1980

Acknowledgement

This report was prepared by the Flue Gas Desulfurization Study Group of the North Atlantic Treaty Organization (NATO) Committee on the Challanges of Modern Society (CCMS). Mr. Frank Princiotta of the United States Environmental Protection Agency serves as Chairman. The members of the Study Group were:

Country	Name	Affiliation
Canada	Mr. M. E. Rivers	Environment Canada
	Mr. T. Bambrough	Air Pollution Control Directorate
Denmark	Mr. B. Colliander	ELSAM (Electrical Cooperative)
Germany (Co-Pilot Country)	Dr. P. Davids	Umweltbundesamt (Federal Environmental Agency)
	Dr. G. Reimann	Federal Ministry of the Interior
	Dr. G. Weisser	Battelle Institute
Italy	Mr. D. Merluzzi	ENEL (State Power Co.)
Netherlands	Mr. R. Bosma	Energy Research Foundation
	Mr. F. VanDerBrugghen	Energy Research Foundation
Norway (Co-Pilot Country)	Dr. O. Erga	Foundation of Scientific and Industrial Research
	Mr. H. Kolderup	Foundation of Scientific and Industrial Research
	Mr. G. Gaupset	State Pollution Control Authority
	Mr. A. Tokerud	A/S Norsk Viftefabrikk
United Kingdom	Dr. J. Bettelheim	Central Electricity Research Laboratory
	Mr. S. Dearnley	Department of Energy
	Mr. A. Littler	Central Electricity Generating Board
	Mr. M. Tunnicliffe	HM. Deputy Chief Alkali and Clean Air Inspector
	Mr. N. Nicholson	Davy Powergas, Ltd.
United States (Pilot Country)	Mr. F. Princiotta	U.S. Environmental Protection Agency
	Mr. R. Gerstle	PEDCo Environmental, Inc.
	Mr. R. Torstrick	Tennessee Valley Authority

BACKGROUND

The rapid evolution of flue gas desulfurization technology along with the increasing interest in this technology for reducing sulfur dioxide emissions prompted the NATO-CCMS to form a Study Group to assess and summarize information on these systems. This study was initiated early in 1977 at a meeting of the member countries' delegates in London. The United States through its Environmental Protection Agency was the lead or pilot country with Norway and the Federal Republic of Germany the co-pilot countries. This study group met at approximately 6 month intervals to review progress, comment on completed work, and plan the succeeding steps.

The initial phase of this study consisted of a survey of existing FGD systems used on larger combustion processes in the NATO countries and Japan. Twelve FGD systems were surveyed and reports summarizing their status were prepared. (NATO-CCMS Report No. 95).

During the second phase of this study an applicability FGD system cost analysis was made. This could assist interested parties in making a proper choice of an FGD process for their particular application. (NATO-CCMS Report No. 97).

SUMMARY OF FINDINGS

In a constant effort to improve existing processes and develop new ones, considerable developmental activity in the flue gas desulfurization (FGD) field is occurring. All of the FGD processes contact the flue gas with reactive material (usually in a liquid slurry or solution) which removes most of the SO_2. The reacted sulfur bearing material is then regenerated and the concentrated SO_2 recovered and used for production of sulfur or sulfuric acid, or the sulfur bearing material is sold (gypsum) or disposed of as waste (sludge). Tables 1 through 3 summarize key factors pertaining to the twelve FGD processes considered in this study by process category. Three process categories were reviewed in this study, namely; 1) the throwaway category where the sulfur bearing sludge or solution is pumped to a pond or into tidal water, 2) the gypsum category where the sulfur bearing compound, calcium sulfate, is produced for sale or disposal, and 3) the regenerative category where sulfur dioxide is recovered for use in the production of saleable sulfuric acid or sulfur.

At the time of the first phase of the study (1978) there were 144 known FGD systems operating on fossil-fueled combustion processes. Of these, 74 were operating on utility boilers representing about 70×10^6 Nm^3/hr of flue gas treatment capacity from 20,000 Megawatts (MW) of electrical generation.

Systems using limestone or lime slurry as the SO_2 absorbing reagent were by far the most common and accounted for about one-half of the 35 operating installations surveyed in this study. These systems were located mainly in the United States and Japan. Table 4 summarizes application of FGD as of December 1977 and delineates the number of systems surveyed by process. Table 5 summarizes survey results which indicate performance and fuel information by process.

To compare cost, nine of the surveyed FGD systems were selected for further study in the second phase of this work. Based on a 500 MW model utility plant, general FGD system costs were estimated for a variety of fuels and fuel sulfur contents. Pertinent data for a high sulfur coal are summarized in Table 6 and show that estimated capital costs vary from 56 to 147 $/KW and annualized cost from 2.9 to 9.5 mills/KWh depending on the process. From 3 to 8 percent of the energy (fuel) input for liquid/gas pumping, reheat and process heat is required to operate the FGD system. Space requirements vary from 2 to 5 hectares for plants with no disposal ponds, and up to 127 hectares for systems using limestone or lime producing sulfur bearing sludge.

Also, a decision aid system has been developed which would allow a potential user of FGD technology to: (1) eliminate certain processes from consideration based on site-specific factors and (2) evaluate the potential efficacy of applicable processes based on performance and cost considerations.

The study recognizes that every FGD system is a chemical processing plant in its own right and not an auxiliary to the main plant (boiler unit, etc). It requires full professional design and proper training of operating staff. The complexity of the regenerative processes is obvious, but the apparent simplicity by comparison of the sludge or gypsum processes can be misleading.

The chemical nature of the FGD processes and their control characteristics will be foreign to most power utility staffs, and this can amplify the difficulty in rectifying any operating problems and maintaining high availabilities.

CONCLUSIONS

Flue gas desulfurization technology is being applied extensively worldwide, with particular activity in the United States and Japan. Such systems represent an important option for the control of sulfur oxides from fossil fuel boilers. Twelve FGD processes have been identified which are commercial or close to commercial, that can be used for a wide range of coal and oil fired boiler applications.

In the United States the primary systems of choice are lime and limestone scrubbers which produce a disposable product. In Japan, lime and limestone systems producing saleable gypsum ($CaSO_4.2H_2O$) predominate. Regenerative processes producing sulfur or sulfuric acid have been applied much less extensively so far, probably due to their complexity and generally higher costs.

FGD systems are chemical processing plants which require full professional design and properly trained operating staffs.

Capital and operating costs associated with such systems are a function of many factors including type of process, fuel type, boiler size, and whether applied to a new or an existing boiler. Site specific costs, such as for materials and for waste disposal, and for land utilization, may have a significant or even over-riding influence.

The technical and economic assumptions used in deriving the comparative cost data are very important and must be understood for each country and site before any projected absolute values can be estimated for a new installation. The value of the NATO-CCMS Report No. 97 does not lie so much in the absolute values, which relate only to present U.S. conditions, but in illustrating the relativities between FGD processes and the economic significance of elements within each process.

FGD energy requirements vary by process, but the non-regenerable processes are unlikely to exceed four percent of the power plant fuel consumption.

In its consistency, scope and depth of technical review this study provides a unique and important summary of the present technical status of major FGD processes and of estimated costs of their construction and operation for a number of defined cases in the USA. It also provides a useful decision aid system which can help boiler system operators in assessing FGD systems in the context of specific situations.

The NATO-CCMS project format which employs a pilot country approach, with expert contribution, has been an effective means of carrying out a survey study of this type.

RECOMMENDATIONS

The study group recommends the following:

A. The results of this study should be disseminated to the NATO countries, and other countries considering sulphur oxide control for fossil fuel boilers.

B. Consideration should also be given to distributing the reports to other international organizations in order to facilitate information transfer.

C. The data summarized in this final report must not be taken in isolation from the data and qualifications in the NATO-CCMS reports Nos. 95 and 97.

D. The study group has noted the continuing improvement in existing FGD systems, the development of new FGD systems, the growing concern about the pollution resulting from solid and liquid wastes from some FGD processes, and the use and development of other techniques to decrease SO_2 emissions to the atmosphere, such as fluidized-bed combustion and spray drying/absorption FGD processes. Because of these developments, consideration of processes for reducing SO_2 emissions should not be limited to those processes included within this study.

E. With the growing international interest in SO_2 control, the study group is strongly of the opinion that a continuing examination and review of existing and newly developed FGD systems and other SO_2 emission reduction systems, and the pollution problems related to these systems, should be undertaken within the NATO-CCMS forum. In a later phase other desulfurization techniques could be evaluated. The pilot country is proposing a meeting in Copenhagen during late May or June to plan and begin implementing this followup effort.

TABLE 1. SUMMARY DESCRIPTION OF FGD PROCESSES - THROWAWAY CATEGORY

FGD process (year of first use)	Primary reagent	Product for disposal	Operating principles	Present status
1 Limestone/sludge (1933)	$CaCO_3$	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with limestone slurry. SO_2 reacts to form insoluble Calcium compounds, which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in USA.
2 Lime/sludge (1972)	CaO	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with slurry of hydrated lime. SO_2 reacts to form insoluble Calcium compounds, which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in USA.
3 Double alkali/sludge (1974)	NaOH or Na_2CO_3 and CaO or $CaCO_3$	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with alkaline sodium based compounds in solution. Used solution regenerated with lime or limestone in separate reactor to form insoluble Calcium compounds, which are separated and partly dewatered for disposal.	Recent commercial operation on industrial sized coal-fired boilers in USA.
4 Seawater scrubbing (1975)	Seawater	Dilute sulfate solution	Flue gases scrubbed with seawater on a once-through system, diluted, oxidized and neutralized, and discharged back to sea.	Commercial operation on small oil-fired boilers in Norway.

TABLE 2. SUMMARY DESCRIPTION OF FGD PROCESSES - GYPSUM CATEGORY

FGD process (year of first use)	Primary reagent	Product for disposal or sale	Operating principles	Present status
5 Limestone/gypsum (1973)	$CaCO_3$	gypsum	Flue gases scrubbed with limestone slurry. Resulting Calcium-sulfur compounds are air-oxidized to gypsum, separated and dewatered.	Commercial operation (coal and oil), principally in Japan.
6 Lime/gypsum (1964)	CaO	gypsum	Flue gases scrubbed with slurry of hydrated lime. Resulting Calcium-sulfur compounds are air-oxidized to gypsum, separated and dewatered.	Commercial operation (coal and oil), principally in Japan; also recently in W. Germany.
7 Double alkali/gypsum (1973)	NaOH or Na_2CO_3 and CaO or $CaCO_3$	gypsum	Flue gases scrubbed with alkaline Na compounds in solution. Used solution regenerated with lime or limestone in separate reactor and the insoluble Calcium-sulfur compounds are air-oxidized to gypsum, separated and dewatered.	Commercial operation on oil-fired boilers in Japan.
8 Dilute sulfuric acid/ gypsum (Chiyoda) (1972)	H_2SO_4 and $CaCO_3$	gypsum	Flue gases are scrubbed with dilute sulfuric acid containing ferric ion catalyst. Air oxidation produces more sulfuric acid, which is bled off and neutralized with limestone. The gypsum is separated and dewatered.	Commercial operation on oil-fired boilers in Japan.

TABLE 3. SUMMARY DESCRIPTION OF FGD PROCESSES - REGENERATIVE CATEGORY

FGD process (year of first use)	Primary reagent	Primary product	Operating principles	Present status
9 Sodium sulfite (Wellman-Lord) (1971)	Na_2CO_3 NaOH	SO_2	Flue gases are scrubbed with sodium sulfite solution and the resulting sodium bisulfite is thermally regenerated to sodium sulfite and SO_2. The SO_2 is then further treated to yield marketable products such as sulfuric acid or sulfur.	Commercial operation on oil-fired boilers in Japan. Recent commercial application on coal-fired boilers in U.S. Also on chemical/oil refinery plants.
10 Magnesium oxide (1971)	MgO	SO_2	Flue gases scrubbed with slurry of hydrated magnesium oxide. Insoluble magnesium sulfite is separated and calcined for recycle of MgO and generation of SO_2 for further treatment.	Commercial operation on oil-fired boilers in Japan. Demonstration plant on coal-fired boiler in USA.
11 Carbon adsorption (1974)	Carbon	SO_2	SO_2 from flue gases is adsorbed on activated carbon, which is then regenerated thermally, releasing SO_2 for recovery.	Demonstration.
12 Copper oxide (Shell) (1973)	CuO	SO_2	SO_2 from flue gases is adsorbed on copper oxide coated alumina. This is then treated chemically to regenerate the adsorbent and produce SO_2 for recovery.	Demonstration.

Table 4. SUMMARY OF FGD APPLICATIONS AS OF DECEMBER 1977

FGD process	Number of surveyed systems and[b] (MW_e) served	Total known operating FGD systems[a]		Number of systems known to be:	
		On power utilities and (MW_e) served	On industrial boilers	Planned/under construction	Closed down
Limestone/sludge	3 (1645)[c]	13 (5640)[d]	0	31	10
Lime/sludge	6 (2098)	11 (3125)	1	16	6
Double alkali/sludge	2 (52)	1 (20)	4	6	2
Seawater scrubbing	1 (50)[e]	0 (0)	1[f]	0	0
Limestone/gypsum	6 (4105)	23 (3511)	10[g]	0	0
Lime/gypsum	2 (787)	11 (1800)	10[h]	4	0
Double alkali/gypsum	4 (646)	7 (1949)	18[i]	0	0
Dilute sulfuric acid/gypsum	2 (373)	4 (1100)	10[j]	0	1
Sodium sulphite	2 (335)	4 (810)	13[k]	3	1
Magnesium oxide	4 (851)	1 (120)	1[l]	1	3
Carbon adsorption	2 (70)	0	1	0	2
Copper oxide	1 (36)	0	1	0	0

[a] Excludes units smaller than 60,000 Nm^3/h (19.2 MW) in Japan, which are unreported in the literature. This small size group may include as many as 500 small commercial non-regenerable sodium based scrubbing systems averaging 20,000 Nm^3/h. In the U.S. there are 3 utility boilers and about 90 non-utility boilers in operation using non-regenerable sodium based systems.

[b] FGD systems. Some systems serve more than one boiler. MW served is the design size of the FGD system not of the boiler.

[c] Sherburne County submitted data on Boilers 1 and 2 totaling 1,440 MW but only one unit was considered at 710 MW.

[d] Includes Shawnee 10A and 10B experimental lime/limestone units.

[e] 3 boilers and 3 systems at one location.

[f] In addition, one system installed on a source other than a boiler (approximately 16 MW unit).

[g] As many as 10 other units are operating on sintering furnaces, glass furnaces and kilns.

[h] In addition, 30 systems installed on processes other than boilers i.e. sintering machines, H_2SO_4 plants, diesel engines, smelters, glass furnaces, and incinerators.

[i] In addition, 5 systems installed on sources other than boilers.

[j] In addition, 3 systems installed on sources other than boilers.

[k] In addition, 10 systems installed on sources other than boilers, e.g., Claus furnaces.

[l] In addition, one copper smelter is operating in Japan.

Table 5. SUMMARIZED DATA ON FGD SYSTEMS INSTALLED ON BOILER PLANTS

FGD process	No. of systems surveyed	MWe range[a]	Predominant fuel		Reported SO_2 removal efficiency range[b], %	Reported plant availability range[b], %	Process capacity range, Nm^3/s[c]
			Type	% Sulfur			
Limestone/sludge	3	115-820	Coal	0.5-5.4	57-92	88-94	82-108
Lime/sludge	6	65-835	Coal	0.8-4.7	70-92	83-100	28-139
Double alkali/sludge	2	20-32	Coal	0.9-5.0	90-99	80-	25-35
Seawater scrubbing	1	(50)[d]	Oil	~3.0	90-97[e]	96-99	17
Limestone/gypsum	6	250-850	Coal	0.6-2.2	90-96	97-100	103-250
Lime/gypsum	2[f]	37-750	g	2.9	80-92	96-98	35-333
Double alkali/gypsum	4	26-450	Oil	2.0-2.9	90-95	95-98	23-355
Dilute sulfuric acid/gypsum	2[f]	20-350	g	3.6[h]	96	~100	270
Sodium sulfite	2	115-220	g	2.5-3.5	90-92	97-99	99-172
Magnesium oxide	4	95-155	g	2.0-3.8	90-95	i	102
Carbon adsorption	2	20-49	Coal	0.9-5.0	70-80	N.A.	10-42
Copper oxide	1	36	Oil	2.5	80-90	N.A.	30

[a] Range of MWe units served by FGD system.
[b] Whole numbers.
[c] Range of individual scrubber (or equivalent absorber) capacity.
[d] Equivalent MWe.
[e] Efficiency dependent on bypass (reheat) flow - see Status Report.
[f] Includes one coal-fired demonstration unit.
[g] Equal number of coal and oil firing systems were surveyed.
[h] Calculated value.
[i] Insufficient data base.
N.A. - Not available.

TABLE 6. ESTIMATED ENERGY, SPACE AND COSTS FOR FGD SYSTEMS APPLIED TO A MODEL NEW 500 MW PLANT IN U.S. CONDITIONS

FGD Process	Energy Consumption,[d] % of input energy	Land Req'd., Hectares	Cost,[b] Installed $/kW	Revenue Requirement mills/kWh
Throwaway Systems				
Limestone/sludge	3.3	127[c]	106	4.9
Lime/sludge	3.2	107[c]	96	5.0
Double-alkali/sludge	2.5	104[c]	107	5.3
Seawater[a]	3.5	2	56	2.9
Gypsum Systems				
Lime/gypsum	3.7	5	88	4.6
Limestone/gypsum (Jet-bubbling reactor)	3.4	5	94	4.1
Regenerative Systems				
Magnesium oxide	6.3	3	137	5.9
Sodium sulfite	8.1	3	137	6.0
Carbon adsorption	1.7	5	147	9.5
Boiler System Without FGD	-	-	710	38.5

[a] All processes applied to 3.5 percent sulfur coal except seawater which is applied to 2.5 percent sulfur oil. 90 percent SO_2 removal is considered in all cases with the FGD system treating all of the flue gas.

[b] All costs are in 1979 U.S. dollars. Actual installed costs range from 0.7 to 1.5 times the indicated value. Revenue requirements include operating and annualized capital costs and correspond to annual revenue requirements.

[c] Includes area for disposal pond, but excludes ash disposal.

[d] With flue gas reheat to 170 F.